Energy Division

WILL COMPETITION HURT ELECTRICITY CONSUMERS IN THE PACIFIC NORTHWEST

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Will Competition Hurt Electricity Consumers in the Pacific Northwest?

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A computer model was developed at Oak Ridge National Laboratory to analyze the electricity production, costs, and prices for two geographical regions for a single year. Bulk-power trading is allowed between the two regions and market clearing prices are determined based on marginal costs. We used this model, ORCED, to evaluate the market price of power over the year 2000 in the Pacific Northwest and California. We found that, absent intervention by the regulators in the Northwest, generation prices would increase 1.1 ¢/kWh on average, from 1.91¢/kWh for the regulated price to 3.02¢/kWh as the competitive price. If regulators use transition charges and price caps, then customers in the Pacific Northwest need not be penalized by the change to marginal-cost pricing. Customer responses to price changes will increase the transfer of power between regions. A gas price increase of 20%, while only raising the average-cost-based price to 1.95¢/kWh, raised the marginal-cost-based price to 3.56¢/kWh. Reductions in hydroelectric resources also dramatically change the price and flow of power.

BACKGROUND

The U.S. electricity industry is undergoing rapid and substantial changes. The key manifestations of these changes are (1) much greater competition and trading in bulk-power markets and (2) the beginnings of retail competition. Consumers and regulators in states that now enjoy low-cost electricity worry that increased competition may benefit customers in high-cost areas but will hurt those in low-cost regions. For example, the Idaho Public Utilities Commission (1996) stated, "...we find that there is evidence suggesting that the majority of Idaho's ratepayers may experience an increase in rates over the long term.... Without adequate oversight, Idaho customers could be required to compete with others for low cost hydroelectricity produced now for the benefit of Idaho customers. "

This refrain—"retail choice is a threat to customers that will increase electric rates"—is not unique to Idaho (Kemezis 1997). Some utilities, consumer groups, state legislatures, and regulators, especially in states that now have low electricity prices, argue for a go-slow approach to increased competition. On the other hand, Costello (1997) argues that, "To restrict the export of a given resource (to reserve it for local consumers, for example) is to presume that some consumers are entitled to a subsidy. A subsidy exists because consumers are paying less for the resource than they would in an open market."

In principle, increased bulk-power trading among regions should lower the total costs to produce and deliver electricity to consumers. Thus, the concern raised in the low-cost states is less about economic efficiency and more about equity. If fully competitive electricity markets develop and electricity costs decline, it should be possible to provide benefits to consumers in both low-cost and high-cost areas. In the long run, competition and the more-accurate price signals associated with such unbundling and choice

should improve economic efficiency. Here, too, it should be possible to provide benefits to consumers in both areas.

The purpose of this analysis is to examine this low-cost versus high-cost issue quantitatively[1]. Few studies concerning the issue have provided quantitative support. A notable exception is a recent study conducted by the Energy Information Administration (EIA 1997), which estimated the effects of competition on electricity prices in 13 regions. The study below focuses on the Pacific Northwest and California as the two regions of interest here.

ANALYTICAL BASIS

Computer Model

We used a new model developed at Oak Ridge National Laboratory to conduct this analysis. The model, developed primarily with support from the U.S. Environmental Protection Agency, is called Oak Ridge Competitive Electricity Dispatch (ORCED). It dispatches generation (the output available from 52 power plants) to meet loads in two regions for a particular year, 2000 in this analysis. The two regions are connected by a single transmission link that is characterized by its capacity (MW), costs (¢/kWh), and losses (percentage of throughput). The loads in each region are represented by load-duration curves for two seasons each year.

Although this spreadsheet model is comparatively simple, it captures the key features of the U.S. electricity system as it might function with competitive bulk-power markets. In particular, generating units bid their variable costs into a market and the market selects the cheapest units to meet increasing demands. The probabilities for forced outages influence the load duration curve used by more expensive plants. Each season is segmented into multiple time periods of constant demand. The markets in the two regions interact during each time period such that the outputs from units in the low-cost region are increased and the outputs from units in the high-cost region are decreased until an equilibrium is reached. All generators are paid the same price during each time period, the price bid by the highest-cost unit then operating, with adjustments due to transmission losses or constraints.

Because ORCED dispatches generators against load-duration curves rather than against chronological loads, some opportunities for trade between regions are not captured by the model. In particular, ORCED, because of the averaging process inherent in load-duration curves, ignores times when forced outages in one region or unusual load differences between the two regions provide opportunities for profitable trades. Also, the model's treatment of only two regions connected by a single transmission link (rather than several regions connected by many links) limits bulk-power transactions. Finally, ORCED cannot account for intra-region transmission constraints that require some uneconomic dispatch of generating units. For example, substantial power flows occur between the eastern and western portions of the Northwest Power Pool, assumed in ORCED to always be unconstrained.

Input Data

We began the present analysis by creating a data set that conforms closely to the year-2000 values of electricity demand, supply, generation mix, costs, and prices that characterize the Pacific Northwest and California/Southern Nevada electricity markets.[2] We obtained these data from the EIA and Resource Data International PowerDat databases. EIA's database includes its *Annual Energy Outlook 1997* (EIA 1996) plus much of the Federal Energy Regulatory Commission's Form 1 data. The Pacific Northwest is a low-cost region primarily because of its large base of hydroelectric resources. California, on the other hand, is a high-cost region, primarily because of the many gas-fired generators in the state.[3] Figure 1 shows marginal production costs (the determinant of spot prices) in the two regions. The nearly 18,000 MW with zero price in California reflect the state's hydro and qualifying-facility capacity. The 36,000 MW with zero price in the Northwest reflect primarily that region's hydro capacity. In both cases, these generators are treated as must-run units in ORCED.

To simplify the analysis and interpretation of results, we assumed that the only new generating units to be built between 1995 and 2000 were those identified by the EIA (primarily, combined-cycle units, combustion turbines, and small hydro). We also assumed no competition-induced reductions in O&M costs

or in generating-unit performance (e.g., lower heat rates and higher availability factors). Finally, ORCED treats generation costs and prices only; the results presented here exclude transmission and distribution costs.

Prices And Costs

ORCED produces several sets of numbers on the prices and costs of generation services, reflecting the perspectives of power producers and consumers, under both traditional regulation (full-cost recovery) and competitive-market conditions. These variables (all expressed in ¢/kWh) include:

Market Price: the hourly and annual average price (weighted by consumption) that customers would face if they purchased all their energy from the hourly spot market (Figure 2). The annual average market price for each region will differ slightly due to load shape differences between the two regions.

Market Price Adjusted for Transition Costs (TCs): TCs[4] are calculated for each generator as the minimum of (a) the generator's unavoidable fixed costs or (b) the difference between revenue and total cost (both expressed in millions of dollars a year). Thus, if revenues exceed the sum of fuel costs, variable O&M costs, and avoidable fixed costs, the extra revenue is used to offset some of the unavoidable fixed cost in computing TCs. On the other hand, if revenues do not exceed avoidable costs the unit should probably be shut down, and TC is capped at the unit's unavoidable fixed cost. If revenues exceed total costs, this "excess" is considered negative TC and is credited to retail customers. The TC adjustment is equal to the total dollar value of TCs for the year in question normalized by total retail electricity sales (¢/kWh) and is added to the market price for every hour of the year.

Full-Cost-Based Price: the price calculated from the ratio of total revenue requirement (which includes variable and startup costs, net power-purchase costs, avoidable fixed O&M costs, plus unavoidable capital costs) to total retail sales. This number is the price that customers would pay if the state PUC continues to regulate utilities as it has in the past. Any excess revenues from wholesale sales relative to wholesale purchases are treated as a revenue credit and used to reduce the price charged to retail customers.

Producer Price: the annual average price (weighted by production) that producers would receive if they sold all their energy into the hourly spot market. When there is no trading between the two regions, the market and producer prices are identical.

Producer Costs: the production expenses, which include three components:
- Variable plus startup costs are the avoidable variable costs associated with running generators, including fuel plus the

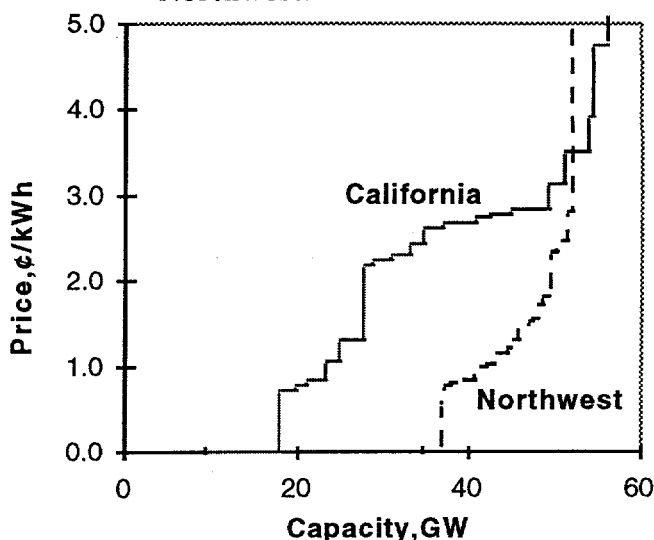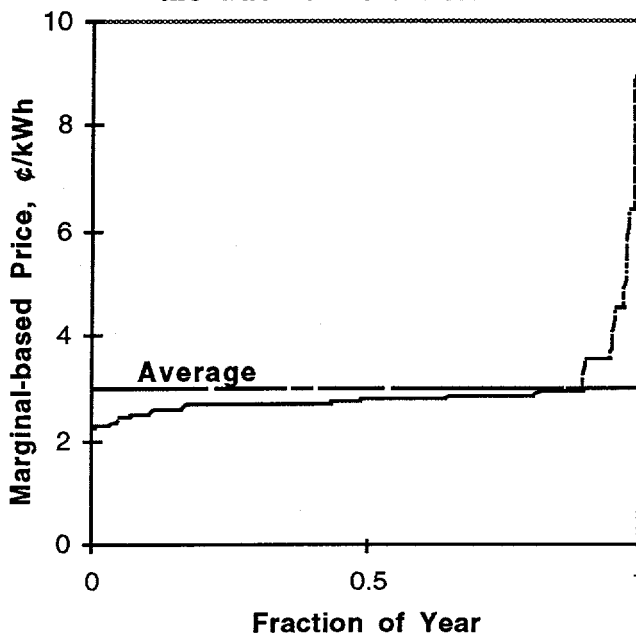**Figure 1. Marginal cost of production in California and the Pacific Northwest.**

Figure 2. Market price in California and the Pacific Northwest.

variable portion of O&M costs. As trading between the two regions increases, variable costs per kilowatt-hour in the low-cost region increase (because it is producing additional electricity from units with higher variable costs for export to the high-cost region), and variable costs per kilowatt-hour in the high-cost region decrease.

- Avoidable fixed costs include the remainder of O&M costs. As trading between the two regions increases, the per-kilowatt-hour value of these costs decreases in the low-cost region (because these fixed costs are spread among more kilowatt-hours of electricity production) and increases in the high-cost region.
- Unavoidable fixed costs are those associated with the plant's capital costs, including depreciation, taxes, interest payment on bonds, and expected return on equity. As trading between the two regions increases, the per-kilowatt-hour value of these costs decreases in the low-cost region (for the same reason that avoidable fixed costs decrease) and increases in the high-cost region.

The sum of these three components equals total producer costs. And the ratio of this total cost to total sales is the producer price noted above. (With trade, producer sales in one region do not necessarily equal consumer purchases in that region.)

RESULTS

We used ORCED to analyze two main scenarios. The pre-competition (base) case depicts the situation just before retail competition occurs, a time when retail electricity prices are fully regulated and bulk-power trading occurs between the two regions as it currently does. This case is equivalent to current conditions projected to the year 2000. The post-competition case is the situation after competition begins, when earnings and retail prices may no longer be regulated. In this situation, customer load levels and load shapes have responded to changes in overall electricity prices and real-time pricing (RTP), and suppliers have retired generating units that are unable to recover their avoidable fixed costs in competitive generation markets. We also ran sensitivity cases to see how bulk-power trading between, and retail prices in, the two regions vary with changes in the amount of hydroelectric resources in the Northwest and changes in natural-gas prices.

Base Case

In this pre-competition case, electricity consumption is slightly lower in the Northwest than in California (243 versus 250 thousand GWh for the year 2000). Demand in the Northwest peaks in the winter at almost 40,000 MW, while demand in California peaks in the summer at 48,000 MW (Table 1). (The California peak is actually higher, but is lowered in ORCED to account for imports from the desert southwest and other regions besides the Pacific Northwest.)

Variable production costs are almost 1.2¢/kWh lower in the Pacific Northwest than in California. Total production costs (essentially equal to retail-customer prices for generation) are 2.1¢/kWh lower. The hourly spot prices of electricity in the two regions are the same because of our assumption that there are no transmission costs or losses between the two regions. The annual market prices differ solely because the load shapes are different in the two regions, with the Pacific Northwest

Table 1. Year-2000 base-case conditions in the Pacific Northwest and California

Factor	Northwest	California
Consumption and production		
Peak demand (MW)	40,000	48,400
Season for Peak	Winter	Summer
Consumption (GWh)	242,800	250,100
Generating capacity (MW)	52,100	56,800
Production (GWh)	259,800	233,100
Reserve margin (%)	30	17
Generation costs and prices (¢/kWh)		
Variable cost	0.75	1.92
Total production cost	1.98	4.03
Market price	3.02	3.11
Regulated price	1.91	3.96

having a higher load factor than California (69% versus 59%); see Figure 3. The regulated price of electricity is about 2¢/kWh lower in the Northwest than in California.

The Pacific Northwest generators have a negative transition cost of $2.7 billion a year. In other words, the aggregate market value of these generators substantially exceeds the aggregate book value. The California generators, on the other hand, have an annual transition cost of $2.1 billion. The California Energy Commission (1997) estimates the net present value of TCs at almost $33 billion, equivalent to about $3 billion a year if spread over ten years.

As expected, producers in the Pacific Northwest sell substantial electricity to customers in California. The sales from the Northwest to California amount to 7.1% of the electricity consumption in the Northwest. Because of the many low-cost generating units in the Pacific Northwest, the vast majority of the flows are from the Northwest to California; specifically, sales from the Northwest to California total 17,300 GWh, while sales from California to the Northwest total 200 GWh in 2000. Because the California units are higher in cost, they generally set the market price of electricity, as shown in Figure 1.
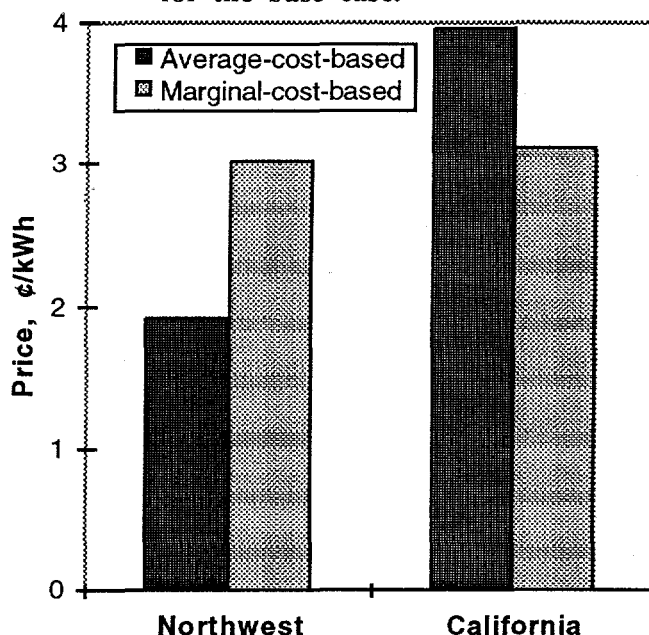
According to EIA's analysis, Northwest sales to California for the year 2000 total 22,000 GWh (Church 1997; EIA 1997), 27% more than the ORCED number. ORCED's temporal limitations (i.e., its use of load-duration curves for two seasons rather than chronological dispatch) average away and therefore mask some of the hour-to-hour differences in loads between the two regions and the associated opportunities for trades in both directions. Also, California is summer peaking, and the Northwest is winter peaking;

Figure 3. Average- and marginal-cost prices for the base case.

ORCED schedules all maintenance outages in the "offpeak" season, which for purposes of this analysis, is the nine-month period from January through May plus September through December. As a consequence, some Northwest units are not available in ORCED to sell to California in the late spring and early fall. Because of these limitations, ORCED runs the California gas plants at higher capacity factors to make up for the import "deficiency."

Post-Competition Case

The post-competition case differs from the base case in two ways. First, customers are assumed to face RTP and to adjust their time-of-use demands accordingly.[5] That is, customers cut demands during high-price periods and increase consumption during low-price periods, which leads to a higher load factor. Also, if overall prices go up or down, overall demand will go down or up. Second, suppliers, no longer operating under an embedded-cost-recovery regime, retire those generating units that are unable to produce sufficient revenues to cover both variable and avoidable fixed costs. We simulate this latter condition by retiring enough of these uneconomical units to bring the reserve margin down to its pre-competition level.

In calculating customer response to RTP, we had to make assumptions on how regulators in both regions would treat TCs. At one extreme, the state regulators in both regions could completely deregulate retail prices and allow customers to face market prices. In the Northwest, retail prices and producer profits would increase; in California, retail prices and producer profits would drop. At the other extreme, the state regulators could allow 100% recovery of all TCs, in which case post-competition prices would be very close to pre-competition regulated prices.

We assumed for the current simulation that state regulators in the Northwest would impose a cap on retail prices to ensure that they do not increase above regulated prices. The Montana legislature (1997) passed a law to cap electricity prices from July 1998 through June 2000 at their July 1, 1998, levels. The California legislature (1996) and PUC imposed a 10% price cut, which translates into a roughly 15% cut in the price of generation. We assumed that TCs would be refunded to customers in the Northwest and collected from customers in California through the energy charge (i.e., in ¢/kWh). As shown in Table 2, the combination of RTP and a price cap leads to essentially no change in total electricity consumption in the Pacific Northwest. On the other hand, RTP combined with a 15% cut in the price of generation leads to a 4.6% increase in both consumption and load factor in California. The California load-shape changes free up transmission capacity so that electricity flows from the Northwest to California increase by 4% from the base case.[6] Because peak demands in the two regions are virtually unchanged between the base case and the post-competition case, no uneconomical generating units are retired (the second factor discussed at the beginning of this section). Market prices in both the Northwest and California increase slightly (by 6%, as shown in Table 3) in spite of the 4% increase in electricity sales from the Northwest to California. These price increases occur because demand is higher in California, leading to the use of more-expensive generating units.

Table 2. Pre- and post-competition electricity use, with post-competition customer response to real-time pricing

	Northwest	California	Total
Electricity use (GWh)			
Pre-competition	242,800	250,100	493,000
Post-competition	242,800	261,500	504,300
Load factor (%)			
Pre-competition	69.4	59.0	68.9[a]
Post-competition	68.6	61.7	71.5[a]

[a] The total load factor is high because the Northwest is winter peaking and California is summer peaking.

As the retail price of electricity changes from market price to market price plus TCs to regulated price (Table 3), producer profits also change (Figure 4). (Profits are defined here as revenue minus avoidable costs but before capital-related costs.) If prices in the Northwest are allowed to increase from their regulated values to market levels, producer profits will increase dramatically from the authorized recovery of unavoidable fixed costs of $1.89 billion to $5.05 billion. Most of this $3.16 billion increment can be assigned to shareholders; none of it is needed for depreciation or interest payments on bonds, but some is needed for taxes. In California, a shift from regulated to market prices would reduce utility recovery of unavoidable fixed costs from $3.68 billion to $2.12 billion.

Table 3. Pre- and post-competition electricity prices (¢/kWh and percentage change from base case)
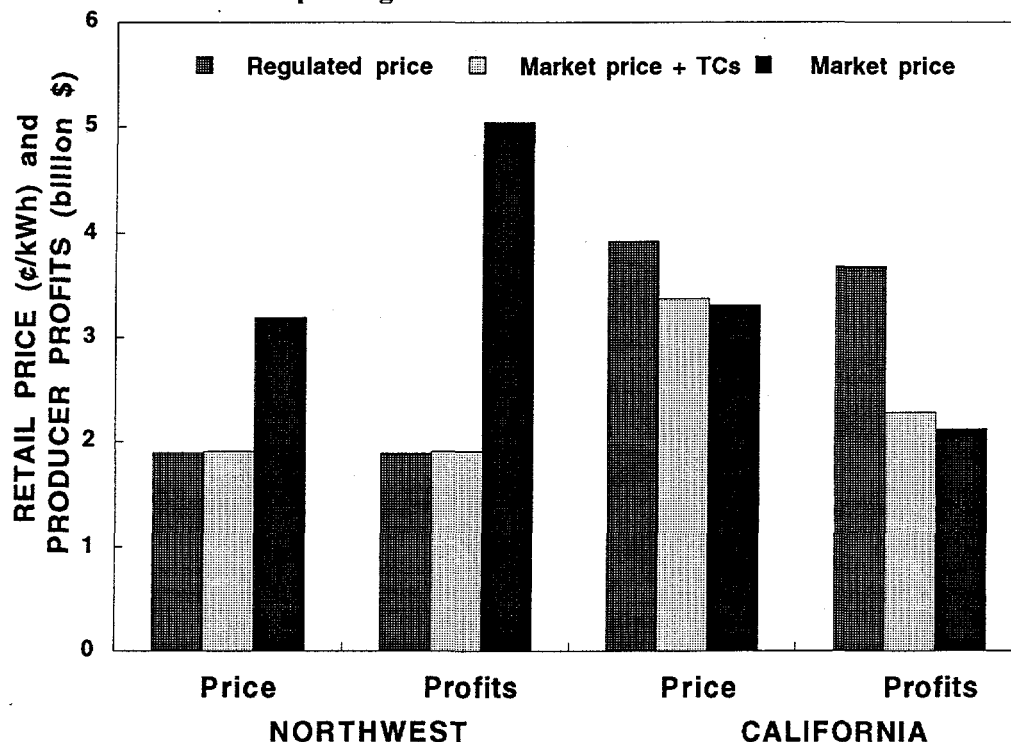
	Pacific Northwest	California
Market price	3.02 to 3.19 (+6%)	3.11 to 3.31 (+6%)
Market price + transition costs[a]	1.91 to 1.89 (-1%)	3.78 to 3.37 (-11%)
Regulated price	1.91 to 1.90 (0%)	3.96 to 3.92 (-1%)

[a]For this case, retail electricity prices in the Northwest are capped at the pre-competition regulated price; prices in California are capped at 85% of the pre-competition level.

Higher Natural-Gas Prices

Beginning with the base case discussed above, we ran a case in which natural-gas prices are 20% higher in both regions. The amount of electricity trading between the two regions is virtually unchanged because of this increase in gas prices. On the other hand, the variable cost of electricity production across both regions increases by 11%, from 1.30 to 1.45¢/kWh (Table 4 and Figure 5). The market price of electricity increases by 17%, from 3.07 to 3.60¢/kWh. Marginal prices increase much more than average prices because gas-fired generation is on the margin for a large fraction of the year. Correspondingly, the

Figure 4. The effects on producer profits of changes in retail electricity prices for the post-competition case in which customers face real-time pricing.
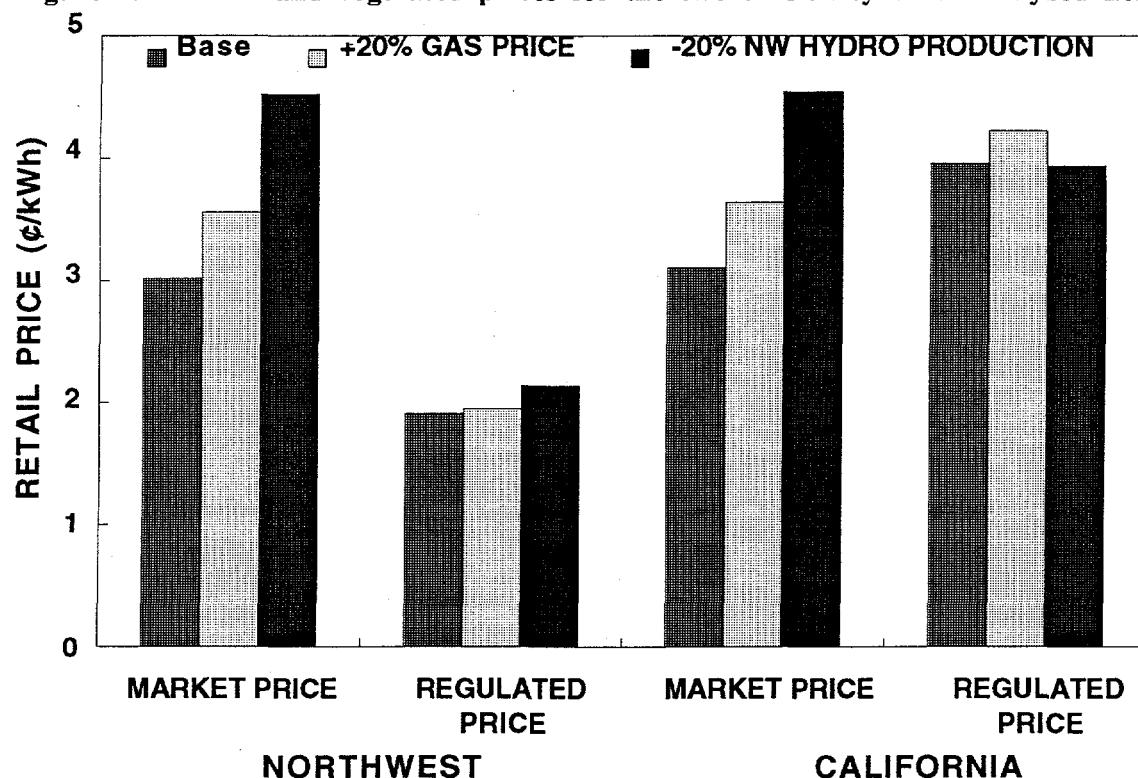

low-cost hydro, which accounts for almost one-third of total electricity production in the two regions, is always inframarginal.

TCs decline in both regions (i.e., the positive TCs in California are smaller, and the negative TCs in the Northwest are higher). The higher price of natural gas makes the generators in California more economical and increases the economic value of the hydroelectric resources in the Northwest. Because of these changes in TCs, the effects of higher gas prices on the sum of market price plus TCs and on regulated prices are much less than the effects on market prices alone. This, of course, is how competitive markets are intended to operate. Competitive prices (reflected here in annual averages of hourly spot prices) are expected to track closely the underlying marginal costs of electricity production. Regulated prices, on the other hand, track average costs.

Table 4. The effects of a 20% increase in natural-gas price on the costs and prices of bulk-power electricity (¢/kWh and percentage change from base case)

	Pacific Northwest	California
Market price	3.02 to 3.56 (+18%)	3.11 to 3.64 (+17%)
Market price + transition costs	1.91 to 1.94 (+2%)	3.78 to 4.07 (8%)
Regulated price	1.91 to 1.95 (+2%)	3.96 to 4.23 (+7%)
Variable cost	0.75 to 0.81 (+9%)	1.92 to 2.16 (+13%)

Figure 5. Market and regulated prices for the two sensitivity cases analyzed here.

Lower Hydroelectric Output

Beginning with the base case discussed above, we ran a case in which the amount of hydroelectric energy produced in the Northwest is cut by 20%. Unlike the case with higher gas prices, lower hydroelectric output dramatically affects trade between the two regions. Sales from the Northwest to California are cut by 87%, from 17,300 to only 2,300 GWh. Sales from California to the Northwest jump from 200 GWh to 11,100 GWh.

Overall, the market price increases by 48%, from 3.07 to 4.54¢/kWh. Because the amount of hydroelectric generation is lower than in the base case, the remaining generating units operate at higher capacity factors. Because the generators operate for more hours, they generate additional revenues, and therefore TCs are lower than in the base case. Even in the Northwest, where one might expect that the loss of 20% of the region's low-cost generation output would increase TCs, this is not the case. The TCs decrease from -1.1 to -2.4¢/kWh in the Northwest and from 0.7 to -0.6¢/kWh in California. Because of these changes in TCs, the sum of market price plus TCs changes much less than does market price; the same is true for regulated price (Table 5 and Figure 5).

Table 5. The effects of a 20% cut in the Northwest's hydroelectric output on the costs and prices of bulk-power electricity (¢/kWh and percentage change from base case)

	Pacific Northwest	California
Market price	3.02 to 4.53 (+50%)	3.11 to 4.55 (+46%)
Market price + transition costs	1.91 to 2.27 (+19%)	3.78 to 3.92 (+4%)
Regulated price	1.91 to 2.27 (+19%)	3.96 to 3.94 (-1%)
Variable cost	0.75 to 0.84 (+12%)	1.92 to 2.02 (+5%)

CONCLUSIONS

This study examined retail electricity prices in the Pacific Northwest and California as they might develop for the year 2000. We analyzed different sets of assumptions concerning electricity production and bulk-power trading between these two regions. We used a simple two-region planning model, ORCED, to conduct these analyses. The purpose of these analyses was to see how retail customers in the Northwest (a region with an abundance of low-cost hydroelectricity) would fare under different conditions. The ORCED analyses deal only with a single year (2000); treat generation only (and exclude transmission, distribution, and customer-service costs); ignore potential costs of making the transition to competitive electricity markets (e.g., to create independent system operators and to support retraining and early retirement activities for utility personnel); and ignore the potential effects of competition on generator productivity (e.g., lower forced and planned outage rates) and on production costs (e.g., lower heat rates and O&M costs).

Even when substantial differences exist in the production costs between two regions, the amount of electricity traded between them may be modest.[7] The limited amount of trading is a consequence of the fact that much of the low-cost generation in the Pacific Northwest is operated at maximum capacity to meet native load in that region. More broadly, the amount of generating capacity in either region available for inter-regional transactions is limited by the loads in both regions.

Absent regulatory intervention, retail competition would increase profits for producers in the Northwest and lower prices for consumers in California at the expense of consumers in the Northwest and producers in California. This finding is consistent with EIA's (1997) results, which showed that competitive prices in two low-cost regions, the Northwest Power Pool and the Mid-Continent Area Power Pool, are likely to be higher than regulated prices.

However, state and local regulators may be able to capture some or all of the increased profits and use them to lower electricity prices in the low-cost region. Perhaps the most straightforward way to allocate the costs and benefits to retail customers is through development of TC charges or credits. Given this option, the consumers in both regions can benefit from competition.

The magnitude and even direction of bulk-power trading between regions depends strongly on the amount of hydroelectric power and energy available in the Northwest. Market prices respond much more strongly to changes in natural-gas prices and hydro output than do regulated prices. Indeed, market prices are intended to closely track changes in marginal costs, while regulated prices typically track changes in average cost.

The bottom line from this analysis is that increased competition *can* benefit retail customers in high-cost regions without harming customers in low-cost regions. Such a desirable outcome, however, is not automatic. State regulators may have to intervene to be sure that what would otherwise be additional profits for the producers in the low-cost region are used to lower prices to retail customers. This conclusion is consistent with a finding from the Northwest Power Planning Council (1997) that "higher average costs in California need not mean higher bills for the Northwest." The Council offers two reasons for its conclusion, also consistent with the present analysis, related to competition in bulk-power markets and treatment of TCs.

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ENDNOTES

1. This paper is based on the report: Hadley, S. And Hirst, E., *Possible Effects of Competition on Electricity Consumers in the Pacific Northwest*, ORNL/CON-455, Oak Ridge National Laboratory, Oak Ridge, TN, January 1998. Contact us at hadleysw@ornl.gov or hirstea@ornl.gov for further information or copies of the report.

2. The Pacific Northwest includes all of Washington, Oregon, Idaho, and Utah as well as western Montana and parts of Nevada and Wyoming (i.e., the U.S. portion of the Northwest Power Pool). The California region includes all of California plus the Nevada Power portion of southern Nevada.

3. We focus here on variable production costs because generators compete with each other in bulk-power markets on that basis only. Fixed costs (fixed O&M costs plus capital costs) affect generator profitability but not the competitive status of generators.

4. Roughly speaking, TCs reflect the differences between the regulated prices for electricity generation and the prices that might occur in fully competitive power markets. These costs can include generating assets, long-term power-purchase contracts, and regulatory assets (Baxter, Hirst, and Hadley 1997). TCs can be positive or negative. The present analysis does not consider regulatory assets, which leads to an underestimate of TCs in California and an overestimate of negative TCs in the Northwest.

5. These analyses assume an overall price elasticity of demand of –0.5 and a time-of-use elasticity of –0.1. The very low value used for customer response to RTP is based on the notion that, by the year 2000, many customers will be unwilling or technically unable to respond to such prices. We ignore the costs and time to install time-of-use metering.

6. When no TCs are allowed to be recovered in California or collected in the Northwest (i.e., retail customers face market prices), bulk-power flows increase from 17,300 to 39,200 GWh. EIA's projected increase in trade between the two regions (from 22,000 to 43,000 GWh) is similar (Church 1997).

7. The EIA (1996) *Annual Energy Outlook 1997* projects that, on average, exports from the 13 regions it analyzed amount to 6% of electricity consumption for the year 2000. California, with net imports equal to almost 23% of retail electricity use, is the major exception.